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IDAHO PUBLIC
UTILITIES COMMISSION

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF AVISTA CORPORATION FOR THE AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC AND NATURAL GAS SERVICE TO ELECTRIC AND NATURAL GAS CUSTOMER IN THE STATE OF IDAHO	)	CASE NO. AVU-E-04-01

COURT REPORTER

COEUR SILVER VALLEY

DIRECT TESTIMONY OF

ANTHONY J. YANKEL

June 21, 2004

Q. PLEASE STATE YOUR NAME, ADDRESS, AND EMPLOYMENT.

A. I am Anthony J. Yankel. I am President of Yankel and Associates, Inc. My address is 29814 Lake Road, Bay Village, Ohio, 44140.

Q. WOULD YOU BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE?

A. I received a Bachelor of Science Degree in Electrical Engineering from Carnegie Mellon University in 1969 and a Master of Science Degree in Chemical Engineering from the University of Idaho in 1972. From 1969 through 1972, I was employed by the Air Correction Division of Universal Oil Products as a product design engineer. My chief responsibilities were in the areas of design, start-up, and repair of new and existing product lines for coal-fired power plants. From 1973 through 1977, I was employed by the Bureau of Air Quality for the Idaho Department of Health & Welfare, Division of Environment. As Chief Engineer of the Bureau, my responsibilities covered a wide range of investigative functions. From 1978 through June 1979, I was employed as the Director of the Idaho Electrical Consumers Office. In that capacity, I was responsible for all organizational and technical aspects of advocating a variety of positions before various governmental bodies that represented the interests of the consumers in the State of Idaho. From July 1979 through October 1980, I was a partner in the firm of Yankel, Eddy, and Associates. Since that time, I have been in business for myself. I am a registered Professional Engineer in the states of Ohio and Idaho. I have presented testimony before the Federal Energy

Regulatory Commission (FERC), as well as the State Public Utility Commissions of Idaho, Montana, Ohio, Pennsylvania, Utah, and West Virginia.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of Coeur Silver Valley.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. My testimony will address the cost-of-service for Schedule 25 customers with emphasis upon directly assigning as opposed to allocating distribution plant to these customers and the rate design for Schedule 25 in order to properly reflect load factor differences within Schedule 25.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS WITH RESPECT TO THE MANNER IN WHICH COSTS SHOULD BE ASSIGNED TO SCHEDULE 25 CUSTOMERS.

A. After reviewing the Company's cost-of-service study, I have concluded that there are some problems with respect to the allocation/assignment of Primary related distribution plant associated with Schedule 25 customers. Basically, the Company is able to (and does properly) assign the actual costs incurred associated with distribution substations to Schedule 25. However, after identifying specific substation costs to directly assign, the Company then goes back to allocation Primary related equipment (between the substations and the customer) in a manner that ignores the fact that these are customers for which specific Primary plant can be isolated and either directly assigned or simply identified as not existing at all. After correcting for only these problems (in plant accounts 364-367), the rate of return for Schedule 25 is significantly increased to the point where it is above the system average rate of return. Based upon this result, I recommend that Schedule 25 be given the average jurisdictional increase.

I have reviewed the rate design for Schedule 25 in connection with the load and load factor of Schedule 25 customers. There is no question that Potlatch-Lewiston is a very special case for Schedule 25 and that rates must be designed with this customer's cost-of-service in mind. However, Coeur Silver Valley is the next largest customer and it has a significantly higher load factor than the remaining Schedule 25 customers. The difference in load factors of the various Schedule 25 customers must be better addressed than in the Company's proposed rate design. I recommend that rates be established which better reflect this difference in load factor and thus cost causation.

Q. ARE YOU ADDRESSING ALL ASPECTS OF AVISTA'S CLASS COST-OF-SERVICE STUDY?

A. No. Due to time constraints, I have not made a complete review of all aspects of the study, but have focused on those areas where major discrepancies exist between the way costs are addressed (allocated/assigned) and the actual costs that are incurred. For example, there are areas such as the change in allocation methodology from the last case that I am aware exists, but have not reviewed.

COST-OF-SERVICE STUDY

Q. WHAT AREAS IN THE COMPANY'S COST-OF-SERVICE STUDY DID YOU ADDRESS IN DETAIL?

A. My focus was on: 1) distribution Accounts 361-367 as they relate to Schedule 25 customers; and 2) how the rates paid by Schedule 25 customers relate to individual customer load factors.

Q. IS THE ALLOCATION/ASSIGNMENT OF DISTRIBUTION RELATED PLANT COSTS THE SAME FOR SCHEDULE 25 AS IT IS FOR ALL OTHER CUSTOMER CLASSES?

A. No. While most[1] distribution plant was allocated to the various rate schedules, Schedule 25 customers received a mixed bag of allocated and directly assigned plant. Generally speaking, this may not be unusual except for the pattern of what plant is allocated compared to what plant is directly assigned.

Direct assignment should be done wherever possible, as it is an accurate reflection of cost causation, while allocation of costs is only done as a surrogate of cost causation. Avista only has 15 customers[2] in its Idaho jurisdiction that are on Schedule 25. These are Avista's largest customers in Idaho. Appropriately, Avista has directly assigned costs associated with Account 361 (Distribution Substation Structures & Improvements) and Account 362 (Substation Equipment) to Schedule 25 as can be seen on Exhibit 301. However, costs associated with

[1] The main exception to this is Street and Area Lighting customers.

Account 364 (Poles and Towers) and Account 365 (Overhead Conductors & Devices) were then allocated to Schedule 25 customers as opposed to directly assigned.

Q. WHAT IS WRONG WITH ALLOCATING ACCOUNT 364 AND 365 COSTS TO SCHEDULE 25 CUSTOMERS?

A. If the costs associated with Accounts 361 and 362 could not have been directly assigned to Schedule 25 (but had to be allocated), then it may have been appropriate to allocate costs associated with Accounts 364 and 365 to Schedule 25 customers. However, the Company was able to isolate and directly assign the costs for Accounts 361 and 362 to Schedule 25, so it is only appropriate to continue to directly assign the primary lines and towers that originated at these facilities and carry electricity to these same Schedule 25 customers.

This may be best understood by an illustration using the Lucky Friday Substation that serves Hecla Mining Company. Starting at the generation level, there is no way to segregate or directly assign generation plant to Hecla Mining Company, so it must be allocated. Likewise, when that electricity is sent over the transmission system, there is no way to segregate or directly assign transmission plant to Hecla Mining Company, so it must be allocated. Electricity next travels through substations. The Lucky Friday Substation is entirely used to serve the Hecla Mining Company so it is not allocated, but 100% directly assigned to Schedule 25. Coming out of this substation, these particular Primary lines are 1,121 feet (0.2 Miles) long and are obviously used to serve only Hecla's Schedule 25 load and should be directly assigned, as was the plant (Accounts 361 and 362) serving those Primary lines.

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[2] Including Potlatch's Lewiston facility.

Q. WHAT DISTORTIONS RESULT WHEN POLES, TOWERS, AND OVERHEAD CONDUCTORS ARE NOT BEING DIRECTLY ASSIGNED TO SCHEDULE 25 CUSTOMERS?

A. Schedule 25 customers are the largest use customers on the system. Collectively, Schedule 25 customers account for 170,611 kW of non-coincident demand out of 610,300 kW listed for all customers[3] or 28%. According to the Company's workpapers[4] there are 3,049 circuit miles of Primary lines in Idaho. If all of the Schedule 25 non-coincident usage were used to allocate this plant, it would mean that 28% or 854 miles of Primary distribution line would be allocated to these 15 customers or about 60 miles of Primary distribution circuits per Schedule 25 customer.

This would be an absurd result and is partially avoided because the Company correctly removes the Potlatch-Lewiston load when it is developing its D08 allocator for Primary related plant. It is my understanding that the Potlatch-Lewiston load is removed because the circuits behind the substation are not used to serve any customers other than Potlatch and are not even owned by Avista.

However, the Company did not go far enough with its assignment of costs to the rest of the Schedule 25 customers. Instead of being <u>assigned</u> Primary plant, the other 14 Schedule 25 customers are <u>allocated</u> Primary distribution plant based upon their non-coincident peak, which is set at 49,849 kW out of a total of 489,538 kW[5], or 10.18% of non-directly assigned Primary distribution plant. At 10.18% of the circuit miles, this means that 310 miles of Primary lines are

[3] See Exhibit 16 Schedule 2 page 31 line 20.
[4] Workpapers TLK-43 and TLK-44

allocated to these 14 customers or 22 miles for each Schedule 25 customer. Although this is better than 60 miles of circuit per customer, it is nonetheless absurd.

Q. IS IT POSSIBLE TO SEGREGATE THE PRIMARY DISTRIBUTION SYSTEM ASSOCIATED WITH ALL OF THE SCHEDULE 25 CUSTOMERS AS IT IS TO SEGREGATE THE POTLATCH RELATED EQUIPMENT?

A. Data has been provided by the Company[6] that lists the number of feet of primary distribution plant serving each of these Schedule 25 customers. Based upon Exhibit 301, all of the substations that are labeled as being 100% assigned to a Schedule 25 customer can easily be reviewed for direct assignment of Primary distribution plant. For those substations with less than 100% assignment of substation costs, the direct assignment of Primary related plant is still quite feasible. For example, if there is 1-mile of primary distribution plant between the substation and a Schedule 25 customer and there are some other customers served off of this same 1-mile stretch, then simply assigning all of the 1-mile of plant to the Schedule 25 customer would be a conservative estimate of the cost responsibility of the Schedule 25 customer.

Q. BASED UPON THE DATA PROVIDED BY THE COMPANY, WHAT TREATMENT DO YOU RECOMMEND FOR THESE COSTS IN THIS CASE?

A. There is no question that <u>allocating</u> 60 or even 22 miles of Primary plant to each Schedule 25 customer is inappropriate. According to the Company, there is a total of only 20.19

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[5] See Exhibit 16 Schedule 2 page 31 line 32.
[6] Response to Coeur Silver Valley Request 8.

miles of Overhead Primary distribution plant and 0.96 miles of Underground Primary distribution plant used to serve all 15 of the Schedule 25 customers. As opposed to being directly assigned plant that is actually used, allocation results in approximately 15 times more[7] Overhead plant and 85 times more[8] Underground plant being associated with these customers than is used by Schedule 25 customers.

All Schedule 25 customers must be treated as Potlatch is treated and have Primary distribution plant directly assigned as opposed to allocated. I recommend using the ratio of the 20 miles of Overhead Primary lines dedicated to Schedule 25 customers divided by the 3,049 miles of Overhead Primary distribution plant in Idaho (0.66%) to allocate/assign Account 364 and 365 to Schedule 25. I recommend using the ratio of the 0.96 miles of Underground Primary lines dedicated to Schedule 25 divided by the 808 miles of Underground Primary distribution plant in Idaho (0.12%) to allocate/assign Account 366 and 367 to Schedule 25.

Q. WHAT IMPACT DOES DIRECTLY ASSIGNING THE COSTS OF THESE FOUR ACCOUNTS HAVE UPON THE RATE OF RETURN FOR SCHEDULE 25?

A. Exhibit 302 is a summary sheet from a cost of service run made where the costs for these four distribution accounts were directly assigned to Schedule 25. Contrary to the Company's filed rate of return for Schedule 25 that was only 25% of the jurisdictional average, the rate of return for Schedule 25 (when using direct assignment) turns out to be 1.03 greater than the jurisdictional average.

[7] 10.18% / 0.66% = 15.4
[8] 10.18% / 0.12% = 84.8

Q. ARE THERE CONCERNS RAISED BY THE COMPANY REGARDING THE DIRECT ASSIGNMENT OF THESE COSTS?

A. Yes. First, the Company is concerned that using the relative length of primary distribution does not capture the relative cost of the primary trunk lines necessary to meet the capacity needs for extra large industrial customers. Although there may be some differences in cost of serving different capacity loads, those costs should be contained within a relatively narrow range for the Company's 13, 24, and 34 kv lines—not in the range of 15-85 times greater as is suggested by the Company's choice of allocation factors compared to direct assignment. Additionally, the age of the Primary lines serving Schedule 25 customers would suggest that they would be relatively cheaper than the cost of lines being installed today and may be cheaper than the average cost of Primary lines. Basically, the argument should not be accepted that the costs of these facilities are higher until actual cost data is provided which demonstrates this to be the case.

Second, the Company contends that the estimates it used for the circuit mileage associated with individual customers may be slightly inaccurate. Be that as it may. I assume the Company did an acceptable job of measuring, but the potential for error always exists. In order to alleviate any concerns in this regard, I conducted another cost of service run using 1.5 times the amount of Primary lines that the Company measured. I assume that the Company's accuracy is well within this factor of 1.5. Exhibit 303 contains a summary of the results assuming that 30 miles of Overhead and 1.5 miles of Underground Primary distribution should be directly assigned to Schedule 25. The resulting rate of return was still above the jurisdictional average rate of return.

RATE DESIGN

Q. THE PRESENT RATE DESIGN FOR SCHEDULE 25 FEATURES A FLAT ENERGY CHARGE AND A DEMAND CHARGE (ABOVE THE MINIMUM) THAT IS FLAT. DOES THIS RATE DESIGN ADEQUATELY REFLECT COSTS FOR SCHEDULE 25 CUSTOMERS?

A. Although there are often good reasons for using rate structures that are flat, this does not insure that the resulting charges will be reflective of cost causation. The Company readily recognizes this phenomenon in this case where it proposes a declining block rate structure for both Schedule 21 and Schedule 25 customers. As stated in Mr. Hirschkorn's direct testimony at page 22:

> Generally, larger use customers under the Schedule are less costly to serve than smaller use customers on a cost per kWh basis, as some fixed costs are spread over a larger base of usage. Therefore, a lower incremental/average rate for service to larger use customers under a Schedule generally is supportable on a cost of service basis…

Based upon the above, Avista is proposing the introduction of a declining block energy charge for Schedule 25 customers.

Q. HOW DOES THE SIZE (USAGE) AND LOAD FACTOR VARY WITHIN SCHEDULE 25?

A. Potlatch-Lewiston is a new addition to Schedule 25 and is approximately three times larger than the rest of Schedule 25 put together. Its load factor is also significantly higher than other customers on this schedule. It appears that the addition of a customer as large as Potlatch-

Lewiston to the Schedule 25 customer group is why a separate designation was made for this customer in the Company's cost-of-service study as well as why the Company is proposing a declining block energy rate structure for Schedule 25.

After Potlatch-Lewiston, Coeur Silver Valley is the largest of the remaining 14 customers on Schedule 25. Exhibit 304 page 1 is a listing of test year monthly energy and billing demand for each Schedule 25 customer[9]. As can be seen from that exhibit, Coeur Silver Valley's energy consumption is about 1.5 times that of the closest Schedule 25 customers, while its billing demand is the third highest of all Schedule 25 customers. The smallest Schedule 25 customer is J. D. Lumber Co. with energy consumptions about 20% that of Coeur Silver Valley and about 1% the size of Potlatch Lewiston.

Additionally, Coeur Silver Valley is not only the largest Schedule 25 customer (excluding the new Potlatch-Lewiston load), but it also has the highest load factor of the group. Exhibit 304 page 2 lists the annual consumption as well as annual billing demands for each of these customers in order to calculate an average monthly load factor[10] for each customer. As can be seen from that exhibit, Coeur Silver Valley has the highest average load factor of 71%, while J.D. Lumber has the lowest at 33%. As a group (excluding Potlatch Lewiston) the average load factor for Schedule 25 is only 53%.

Q. WHAT IMPLICATION DOES THIS DIFFERENCE IN LOAD FACTOR HAVE ON COST OF SERVICE AND RATE DESIGN?

[9] Data provided as a workpaper in response to Staff Request 29.
[10] (annual energy) / (total billing demands) / (730 hrs. per month)

A. All things being equal, higher load factor customers are generally much cheaper to serve than lower load factor customers. The fact that the Coeur Silver Valley load has an average load factor that is over 2 times the worst average load factor on the rate schedule in which it finds itself means that there are large differences in meeting demand obligations between Coeur Silver Valley and the other Schedule 25 customers. If Coeur Silver Valley is going to pay rates that are reflective of its cost causation, then the design of the rates within Schedule 25 must be such that higher load factor customers on the rate schedule are rewarded with lower rates.

Q. DOES THE PRESENT SCHEDULE 25 RATE FULLY REFLECT THE DIFFERENCE IN DEMAND RELATED COSTS FOR MEMBERS OF THIS RATE SCHEDULE?

A. Although there is some recognition in the existing rate schedule of the impacts of load factor, that recognition is minimal. Present rates have a minimum charge of $7,500 for the first 3,000 kW of demand and a $2.25 per kW charge for usage over 3,000 kVA. Assuming more than the minimum, at a 71% load factor, this translates into 0.434 cents per kWh[11], which amounts to a 15% addition to the energy charge of 2.874 cents per kWh. At the Schedule 25 average load factor of 53% the demand charge translates into 0.582 cents per kWh, which is only a 20% addition over the energy cost. The effective rate for usage over 3,000 kVA per month is:

L. F.	Mills / kWh
71%	33.08
53%	34.56

Although there is a 4.5% difference in the rates paid between these two load factors, this differential is not a strong price signal to reflect the difference in cost causation between the two different load factors.

I will use the ratio of the demand charge to the energy charge as a gauge of the relative dependence placed upon the demand component compared to the energy component of the rate. In this particular case with a demand charge of $2.25 per kW and an energy charge of 2.874 cents per kWh the ratio would be 78 (2.25 / 0.02874 = 78.3).

Q. HAS THE COMPANY FILED DATA THAT WOULD SUGGEST A SIGNIFICANTLY DIFFERENT LEVEL OF DEMAND CHARGES FOR SCHEDULE 25?

A. Yes. On Exhibit 16, Schedule 2, page 3, line 6 the Company calculated the demand related costs for serving Schedule 25 customers at current level of Return as $7.02 per kW per month. Although I do not agree that this calculation should be taken literally as the basis for setting demand charges, the fact that present demand charges for Schedule 25 are approximately 1/3rd of this level suggests that the demand charges may be too low.

Q. DOES THE COMPANY'S PROPOSED SCHEDULE 25 RATE FULLY REFLECT THE DIFFERENCE IN COST CAUSATION FOR MEMBERS OF THIS RATE SCHEDULE?

A. No. The Company's proposed Schedule 25 rates do little to help the load factor diversity that I am addressing. I assume (but do not know) that the new declining block energy

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[11] $2.25 / 730 hrs / 0.71 = $0.00434

rate appropriately sets a revenue requirement for the Potlatch-Lewiston load that matches its cost-of-service. However, it does little to address the load factor differentials for the rest of the Schedule 25 customers.

The proposed rates have a $2.75 per kW charge for usage over 3,000 kVA. At Coeur Silver Valley's average load factor of 71% this translates into 0.531 cents per kWh while at a 53% load factor it translates into 0.711 cents per kWh. With the proposed tail block energy rate of 3.420 cents per kWh, the effective rate for usage over 3,000 kVA per month is:

L. F.	Mills / kWh
71%	39.51
53%	41.31

Once again, the difference in the rates between these two load factors (4.6%) is not significant enough to reflect the difference in cost causation. In this case the proposed ratio of the demand to energy rate is 80 (2.75 / 0.03420 = 80.4) or not much of a change.

Q. IS THERE ANOTHER UTILITY TO WHICH THE COMMISSION COULD TURN THAT PLACES MORE EMPHASIS UPON DEMAND RELATED CHARGES?

A. Yes. This Commission recently concluded a major rate case with Idaho Power. Idaho Power's Schedule 19 serves customers in a similar size range to that of Avista's Schedule 25. It is interesting to note, that the present energy rates for Idaho Power's Schedule 19 have been set at 2.8486 cents per kWh, which is almost the same as Avista's present energy rate of 2.8740 cents per kWh for its Schedule 25 customers. In contrast to the closeness of these energy rates, Idaho Power's demand charge for Schedule 19 is $3.21 / kW, while Avista's demand charge for Schedule 25 is $2.25 / kW (for usage greater than 3,000 kW). The ratio of the demand to energy rate for Idaho Power's Schedule 19 is now set at 113 (3.21 / .028486 = 112.7). Additionally, Idaho Power's Schedule 19 has a "Basic Load Capacity" rate that increases the demand charge and thus this ratio even higher.

Idaho Power's rates for Schedule 24 (Irrigation Pumping) now has a demand charge of $4.00 per kW and an energy charge of 3.244 cents per kWh. The ratio of demand to energy charges in this case is 123 (4.00 / .03244 = 123.3). In spite of the fact that it is important to keep this ratio for Irrigation customers as low as possible because Irrigators have effectively no discretion regarding their demand levels, this ratio is significantly above the 78 calculated for Avista's Schedule 25.

Q. HOW CAN THIS PROBLEM BE CORRECTED?

A. There are two ways to correct this problem of not assigning enough costs to low load factor customers. The first way is to increase the demand charge and lower the energy charge(s). The second method is to develop a declining block energy rate that is load factor dependent, i.e., the first so many kWh per kW are priced at one rate while usage above that level is priced at a lower rate. I do not have a preference as to which method the Commission should adopt. I do recommend that whatever method the Commission uses, it should target a ratio of demand to energy charges of at least 120 for Schedule 25.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

AVISTA UTILITIES
Distribution Substation Direct Assignment
Idaho Jurisdiction Electric Cost Study
Twelve Months Ended December 31, 2002

IDAHO SUBSTATION	12/31/2002 ACCOUNT 361	12/31/2002 ACCOUNT 362	SCHEDULE 25 PERCENTAGE	ACCOUNT 361 DIRECT ASSIGN	ACCOUNT 362 DIRECT ASSIGN	
APPLEWAY 115	68,755	852,020	11%	7,563	93,722	
CALADAY 13	2,029	9,309	100%	2,029	9,309	
COEUR D'ALENE 15TH ST 115 NEW	89,257	945,211	4%	3,570	37,808	
Coeur Shaft Sub	1,798	22,472	100%	1,798	22,472	
Diamond Match 60	1,481	136,286	100%	1,481	136,286	
KAMIAH 115	39,912	266,300	18%	7,184	47,934	
KOOSKIA 115	5,244	459,909	28%	1,468	128,775	
LUCKY FRIDAY 115	6,651	40,872	100%	6,651	40,872	
Moscow City	86,918	742,974	15%	13,038	111,446	
NORTH MOSCOW 115	10,275	167,177	33%	3,391	55,168	
OSBURN 115	9,773	158,362	50%	4,887	79,181	
Prairie BPA	63,440	537,528	14%	8,882	75,254	
Priest River	17,986	567,422	57%	10,252	323,431	
ST. MARIES 115	78,493	473,624	20%	15,699	94,725	
SOUTH LEWISTON 115	63,572	826,547	10%	6,357	82,655	
				94,250	1,339,038	1,433,288
SCHEDULE 25P						
CLEARWATER 115	73,214	1,848,039	100%	73,214	1,848,039	1,921,253

	Account 361	Account 362	Total
Total Ending Balance 12/02 of Accounts	2,704,872	23,399,297	26,104,169
Less: Directly Assigned Plant	-167,464	-3,187,077	-3,354,541
Assignment Demand NCP-2	2,537,408	20,212,220	22,749,628

Exhibit 301

Sumcost
Scenario: Company Base Case
Direct Assign Primary Plant
Coeur Silver Vallley Data Request 8

AVISTA UTILITIES
Cost of Service Basic Summary
For The Twelve Months Ended December 31, 2002

Idaho Jurisdiction
Electric Utility

	(b) (c) (d) (e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
			Residential	General	Large Gen	Extra Large	Potlatch	Pumping	Street &
		System	Service	Service	Service	Gen Service	Ex Lg Gen Svc	Service	Area Lights
	Description	Total	Sch 1	Sch 11-12	Sch 21-22	Sch 25	Sch 25P	Sch 31-32	Sch 41-49
	Plant In Service								
1	Production Plant	300,269,000	103,855,863	23,871,210	64,089,462	28,322,636	74,527,729	4,560,417	1,041,683
2	Transmission Plant	109,001,000	37,345,154	8,575,673	23,320,080	10,300,710	27,407,393	1,663,998	387,992
3	Distribution Plant	257,643,000	130,693,683	33,450,789	71,258,291	2,277,067	2,125,817	5,300,802	12,536,552
4	Intangible Plant	11,353,000	4,905,049	1,085,807	2,159,794	810,096	2,138,084	170,709	83,462
5	General Plant	36,524,000	18,936,429	4,095,165	6,117,540	1,799,957	4,636,235	539,983	398,691
6	Total Plant In Service	714,790,000	295,736,177	71,078,645	166,945,167	43,510,466	110,835,257	12,235,908	14,448,380
	Accum Depreciation								
7	Production Plant	(91,465,000)	(31,590,537)	(7,260,043)	(19,529,251)	(8,629,804)	(22,746,584)	(1,390,227)	(318,554)
8	Transmission Plant	(36,394,000)	(12,469,056)	(2,863,304)	(7,786,268)	(3,439,272)	(9,150,968)	(555,587)	(129,546)
9	Distribution Plant	(75,640,000)	(38,096,555)	(9,817,412)	(19,619,574)	(623,848)	(546,491)	(1,527,105)	(5,409,017)
10	Intangible Plant	(1,893,000)	(903,489)	(197,382)	(337,595)	(113,219)	(295,660)	(28,213)	(17,443)
11	General Plant	(16,434,000)	(8,520,460)	(1,842,622)	(2,752,592)	(809,892)	(2,086,077)	(242,966)	(179,391)
12	Total Accumulated Depreciation	(221,826,000)	(91,580,096)	(21,980,763)	(50,025,279)	(13,616,034)	(34,825,780)	(3,744,097)	(6,053,951)
13	Net Plant	492,964,000	204,156,081	49,097,882	116,919,888	29,894,432	76,009,477	8,491,811	8,394,429
14	Accumulated Deferred FIT	(61,593,000)	(25,474,097)	(6,130,524)	(14,427,654)	(3,735,958)	(9,509,603)	(1,056,485)	(1,258,680)
15	Miscellaneous Rate Base	8,836,000	2,756,005	656,928	2,003,272	904,756	2,352,195	136,172	26,671
16	Total Rate Base	440,207,000	181,437,989	43,624,286	104,495,506	27,063,230	68,852,070	7,571,499	7,162,420
17	Revenue From Retail Rates	146,248,000	52,648,000	16,212,000	34,804,000	10,475,000	27,696,000	2,549,000	1,864,000
18	Other Operating Revenues	21,677,000	7,598,479	1,755,180	4,669,859	1,988,040	5,226,957	332,976	105,510
19	Total Revenues	167,925,000	60,246,479	17,967,180	39,473,859	12,463,040	32,922,957	2,881,976	1,969,510
	Operating Expenses								
20	Production Expenses	79,522,000	27,179,034	6,239,677	17,023,454	7,518,503	20,060,876	1,215,561	284,895
21	Transmission Expenses	5,485,000	1,879,232	431,533	1,173,481	518,338	1,379,158	83,733	19,524
22	Distribution Expenses	6,495,000	3,031,498	929,068	1,864,770	67,479	67,378	155,495	379,313
23	Customer Accounting Expenses	4,296,000	3,174,073	712,481	196,952	55,870	96,200	51,053	9,370
24	Customer Information Expenses	1,480,000	589,887	129,334	283,641	124,152	326,637	21,592	4,756
25	Sales Expenses	421,000	134,538	30,672	91,568	40,311	115,486	6,659	1,767
26	Admin & General Expenses	17,888,000	8,940,189	1,968,234	3,189,852	917,915	2,378,876	271,669	221,265
27	Total O&M Expenses	115,587,000	44,928,450	10,441,000	23,823,718	9,242,568	24,424,611	1,805,762	920,891
28	Taxes Other Than Income Taxes	7,438,000	3,127,197	765,287	1,813,904	399,604	1,013,140	132,467	186,399
29	Other Income Related Items	0	0	0	0	0	0	0	0
	Depreciation Expense								
30	Production Plant Depreciation	7,933,000	2,759,593	634,649	1,690,789	747,420	1,953,357	120,107	27,085
31	Transmission Plant Depreciation	2,532,000	867,496	199,206	541,706	239,277	636,650	38,653	9,013
32	Distribution Plant Depreciation	5,670,000	2,820,382	728,701	1,499,445	49,523	48,654	114,625	408,670
33	General Plant Depreciation	3,892,000	2,017,867	436,381	651,886	191,804	494,038	57,541	42,485
34	Amortization Expense	367,000	134,172	31,004	77,216	34,225	83,910	5,401	1,073
35	Total Depreciation Expense	20,394,000	8,599,510	2,029,941	4,461,041	1,262,248	3,216,609	336,327	488,324
36	Income Tax	3,794,000	556,006	732,442	1,451,461	241,304	660,861	94,040	57,886
37	Total Operating Expenses	147,213,000	57,211,163	13,968,670	31,550,124	11,145,725	29,315,221	2,368,596	1,653,501
38	Net Income	20,712,000	3,035,315	3,998,509	7,923,736	1,317,316	3,607,736	513,379	316,009
39	Rate of Return	4.71%	1.67%	9.17%	7.58%	4.87%	5.24%	6.78%	4.41%
40	Return Ratio	1.00	0.36	1.95	1.61	1.03	1.11	1.44	0.94
41	Interest Expense	20,250,000	8,346,345	2,006,765	4,806,907	1,244,938	3,167,270	348,297	329,479

Assign
Scenario: Company Base Case
Direct Assign Primary Plant
Coeur Silver Valley Data Request 8

AVISTA UTILITIES
Cost of Service Calculation
For the Year Ended December 31, 2002

Electric Utility

Idaho Jurisdiction

Functionalization and Classification

(k) Account Description	(l)	(m)	(n) Notes	(o) Functional Allocation	(p) Class Allocator	(q) Proforma Totals	(r) Functional Totals	(s) Residential Service Sch 1	(t) General Service Sch 11-12	(u) Large Gen Service Sch 21-22	(v) Extra Large Gen Service Sch 25	(w) Potlatch Ex Lg Gen Svc Sch 25P	(x) Pumping Service Sch 31-32	(y) Street & Area Lights Sch 41-49
Rate of Return						4.71%	4.71%	1.68%	9.18%	7.60%	4.74%	5.24%	6.79%	4.42%

Exhibit 303

YANKEL

EXHIBITS 304 & 305

CONFIDENTIAL